Report of the Settlement Subgroup

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Introduction

The Settlement subgroup met four times. The purpose of the meetings was to recommend to the Vermont Public Service Board the best methods to administer the energy accounting and financial aspects of the "Standard Offer" portion of the SPEED program. In general, the settlement requirements are described in Act 45 as follows:

> *(2) The SPEED facilitator shall distribute the electricity purchased and any associated costs to the Vermont retail electricity providers based on their pro rata share of total Vermont retail kWh sales for the previous calendar year, and the Vermont retail electricity providers shall accept and pay the SPEED facilitator for those costs.*
>
> *(3) The SPEED facilitator shall transfer any tradeable renewable energy credits attributable to electricity purchased under standard offer contracts to the Vermont retail electricity providers in accordance with their pro rata share of the costs for such electricity as determined under subdivision (2) of this subsection, except that in the case of a plant using methane from agricultural operations, the plant owner shall retain such credits to be sold separately at the owner's discretion.*
>
> *(4) The SPEED facilitator shall transfer all capacity rights attributable to the plant capacity associated with the electricity purchased under standard offer contracts to the Vermont retail electricity providers in accordance with their pro rata share of the costs for such electricity as determined under subdivision (2) of this subsection.*

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Settlement of Producer Payments

The billing and payment procedure used to pay the producer for generation was discussed. For the Rule 4.100 projects this procedure is as follows: the Purchasing Agent interrogates the output meter and acquires the hourly output data for each project. The hourly output data for each project is then evaluated against the applicable power purchase rate for that time frame. Monthly invoices of the amounts owed each producer are generated. The total monthly amount owed to the producers is then distributed pro rata to each of the Vermont utilities along with the pro rata share of the administrative fees of the Purchasing Agent owed by the utilities. The utilities pay Purchasing Agent their pro rata share of total producer monthly bills and administrative fees. The Purchasing Agent then remits those revenues to the producers less the producers' share of Purchasing agent administrative fees. The subgroup was satisfied that this billing model will work for the SPEED facilitator to settle payments to the standard offer projects as well. This is the method recommended for settlement of producer payments.

Settlement of Utility Benefits/Liabilities of Standard Offer Projects

A goal of this subgroup was to evaluate potential market settlement methods that maximize each project's value (energy, capacity, RECs etc.) to the utilities, while attempting to minimize administrative costs that will ultimately be borne by utility customers. Craig Kieny (VEC) prepared an outline (Attachment A) which identifies the various wholesale market settlement components (i.e. energy, capacity, ancillary products, ISO fees, etc.).

The subgroup recognized that some projects, because of size, may possess greater ability than others to economically absorb various administrative costs associated with settlement. As the result, the subgroup developed settlement options for "larger" and for "smaller" projects.

Settlement for "Larger" Projects

The subgroup considered these methods for settlement of "larger" standard offer projects:

1. **Register projects with ISO-NE**

   ISO–NE would settle the projects through the established wholesale market settlement processes in the same way that the current Rule 4.100 projects are settled. The SPEED facilitator would interrogate the producer meters on a daily basis and transmit the hourly generation information to VELCO. VELCO would then transmit this information to ISO-NE within 36 hours after the operating day. ISO-NE, in accordance with the pro rata "ownership" percentage assigned to each purchasing utility designated on the ISO-NE asset registration form, would then "disaggregate" the producer's output and distribute it to each of the Vermont utility's market settlements.

2. Treat the projects as "load reducers" with ISO–NE settlement

The SPEED facilitator would interrogate producer meters daily and transmit the hourly information to VELCO. VELCO would then "disaggregate" the producer's output and distribute it pro rata to each of the Vermont utilities so that each Vermont utility's hourly load would be reduced by their pro rata allocation of generation. VELCO would then transmit the adjusted load data to ISO-NE (also within the 36 hour window). ISO-NE would see Vermont loads which are net of the generation of the standard offer projects. Therefore market settlements calculated for each Vermont utility would be based on that reduced load in all markets and for all charges that use load as the basis for allocation, including ISO-NE administrative fees.

Ken Nolan (BED) reviewed ISO-NE rules and determined that "generators smaller than 1 MW have the unilateral right to elect treatment as load reducers, and further that units 5 MW or smaller, which do not meet the ISO telemetering requirements to be modeled as a generator in the ISO system, have the option to seek treatment as load reducers as well." All standard offer projects fit into this size requirement.

Ken Nolan asserts that "Manual 28 of the ISO-NE rules clearly assigns the responsibility for: a) mapping "load assets" to each Market Participant's "Assigned Meter Reader" (in Vermont this is VELCO); and, b) ensuring that the loads submitted to ISO accurately represent each Market Participant's share of the load in each Load Zone. Ken further asserts that "once a generator has chosen to be a "load reducer" it is the Assigned Meter Reader's responsibility to ensure that it is accurately reflected in each Market Participant's load."

3. Treat projects as load reducers with after-the-fact "financial settlement"

The third method evaluated by the subgroup, was for the SPEED facilitator to perform a "financial settlement" of all utility market revenues and charges after the end of each month. This method would eliminate the requirement to interrogate each producer meter daily. VELCO would not "disaggregate" and allocate the generator output. The generation from the standard offer projects would be treated as a load reduction for each <u>host</u> utility inside ISO-NE wholesale market settlements. After the end of the month, ISO-NE publishes values for various settlement components for the previous month. Using this information, the SPEED facilitator would perform an after-the-fact financial settlement of each host utility to remove all the settlement effects of the generation from the host utility's market settlements. The SPEED facilitator would then disaggregate and distribute pro rata the ISO-NE revenues and charges to each of the purchasing

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utilities. The calculations would also have to take into account each Vermont utility's monthly peak load as well as the yearly Vermont peak load coincident with the ISO-NE peak load.

Recommendation for settlement of "larger" Standard Offer projects

For two reasons the subgroup reached consensus that the standard offer projects should be treated as "load reducers".

First, the subgroup believes that the most value can be extracted for utility customers using this model. When utility loads are reduced, charges to serve that load are reduced, as are all other charges that are allocated based on load obligations, of which there are many. This value is expected to exceed that value for ISO-NE registered assets that simply receive the energy price at the generator pricing node, plus any capacity credits.

The subgroup also recognized that it will be difficult for the standard offer projects to get credit for capacity if they are registered ISO-NE generation assets. The Forward Capacity Market, which takes effect in 2010, will not accept projects of less than 100 KW. The subgroup felt that many of the standard offer projects will be less than 100 KW. Additionally, projects greater than 100 KW participating in the Forward Capacity Market, would have had to bid into the market three years in advance of the 2010 Forward Capacity Auction deadline (and subsequent capacity commitment periods) in order to receive capacity credit in the annual auction. This bidding process presents many administrative and financial challenges, especially for small projects. It is likely that if the standard offer projects over 100 KW were to bid into the Forward Capacity Market there would be several years of delay before the majority of the associated capacity value would be realized by the utilities. Reconfiguration auctions provide subsequent opportunities to receive some capacity value when annual auction deadlines are missed, but the value of such reconfiguration auctions are expected to be significantly less than the annual auctions.

Secondly, the subgroup anticipates that many of the standard offer projects will be solar. Solar projects will most likely be assigned very low capacity values under ISO-NE capacity determinations. However, it is likely that the utilities may receive a higher financial benefit from solar projects if solar projects can reduce utility peak loads.

This reasoning led the subgroup to focus on methods 2 and 3 above. Ultimately it was decided that method 2 is more administratively feasible, being simpler to implement and less subject to error. The subgroup consensus is to recommend method 2 for settlement of the utility benefits and costs for "larger" standard offer projects.

Settlement for "Small" Standard Offer Projects

The subgroup grappled with the intent of the law regarding project size and debated whether an alternative settlement method was appropriate for small projects. The subgroup recognized that smaller projects (e.g. <15 KW) may have monthly revenue of less than $200. At the present time, meter interrogation on a daily basis requires a phone line and interrogation costs estimated to be up to $160/month. To accommodate "smaller" projects two additional settlement models were evaluated which do not require daily meter interrogation:

4. **Treat projects as "load reducers" with 90-day ISO-NE "Resettlement"**

   The meters would be read manually once a month by the host utility and the hourly generation data submitted to the SPEED facilitator and VELCO. VELCO would then adjust and recalculate each utility's load and submit to ISO-NE for 90-day resettlement. This method avoids daily meter interrogation and associated costs of telemetry.

5. **Treat projects as "load reducers" and assign directly to the host utility**

   This model assumes that projects will be developed and located geographically and in quantities that will approximate each utility's pro rata share of retail sales, thus eliminating the need to allocate project output. Each host utility would be billed for the amount of output it receives.

Recommendation for Settlement of "smaller" Standard Offer projects

VELCO commented that resettlement by VELCO (method 4) is not a feasible option due to the significant manual processes for VELCO that would affect settlement every hour of every month. The subgroup participants also rejected method 5 because of potential inequities should "smaller" standard offer projects not locate geographically and in quantities that are pro rata to utility retail sales.

The settlement method being recommended for the larger projects, while being the preferred settlement method, was determined to be economically challenging for smaller projects because of the cost of the daily meter interrogation necessary to meet the submittal deadline to ISO-NE. Smart Grid implementation may substantially reduce the costs of such telemetry in the future and make this settlement method more feasible for small projects. The subgroup recommends that method 3, "financial settlement" by the SPEED Facilitator, be used for settlement of the smaller projects until such time as the cost of daily meter interrogation can be significantly reduced via Smart Grid implementation. As part of this recommendation the subgroup recommends that all projects, regardless of size, be subject to the same metering requirement; electronic, time-of-use meter with at least two channels of interval data storage and an internal modem.

Size distinction between "larger" and "smaller" Standard Offer projects

Next the subgroup discussed what constituted a "larger" project and what constituted a "smaller" project for determination of settlement methods. Consensus was reached by the subgroup that projects greater than 15 KW should be settled as "load reducers" through VELCO and ISO-NE (method 2) and that projects 15 KW and smaller could be settled using a monthly after-the-fact "financial settlement" (method 3). This subgroup recommendation is somewhat arbitrary, however it reflects a bias of the subgroup to accurately allocate the majority of the utility benefits and costs through VELCO and ISO-NE.

Recommendation for Settlement of Renewable Energy Credits (RECs)

Settlement of the RECs was the last task considered by the subgroup. Kirk Shields (CVPS) prepared a flow chart (Attachment B) which shows the meter data and generator emissions reporting paths to the NEPOOL–GIS (Generator Information System) for a generator registered with ISO-NE and for unregistered (load reducer) generators. The subgroup also considered the possibility of monetizing the RECs in a "voluntary market" outside of the NEPOOL-GIS market, such as the voluntary carbon market. The subgroup received information from Native Energy that the "voluntary market" for carbon was unlikely to value RECs nearly as highly as they are valued for compliance purposes by New England states with mandatory Renewable Portfolio Standards (RPS). The "voluntary market" alternative was not pursued further.

The subgroup reached consensus that settling the projects as "load reducers" does not create any barriers to settlement of the RECs through the NEPOOL-GIS system. The Power Purchase Agreement will give the SPEED facilitator ownership rights to the RECs for all projects, except for farm projects which retain ownership of the RECs. The SPEED Facilitator will register each project with the NEPOOL-GIS system. The SPEED Facilitator will also achieve eligibility for each project in the various New England states that have an RPS. The SPEED Facilitator will then submit total monthly generation for each project to the NEPOOL-GIS system. A third party independent meter reader may be necessary in some cases to meet individual state requirements. It is anticipated that the SPEED Facilitator can be certified as a third party meter reader, although other entities may also be able to serve this function. The SPEED Facilitator will then transfer title to the RECs on a pro rata basis to each utility's GIS account. This is the recommended method for settling the RECs.

Additional Recommendations

Several of the subgroup members felt strongly that it is in the best interests of all stakeholders, including utility customers, legislators and regulators, to have transparent and accurate cost information maintained and available as the program evolves in order to aid future decision-making processes. This goal can be achieved by the Board requiring each purchasing utility and the SPEED facilitator to track and account for all costs associated with the Standard Offer program in order to provide the best information for future evaluation and discussion of the Standard Offer program. Examples of costs, though not intended to be a comprehensive list, that otherwise may be hidden or obscured from view are: incremental metering costs; incremental administrative and other labor costs; legal costs; VELCO services costs; equipment costs; ISO transaction costs.

End

Attachment A

SETTLEMENT WORKING GROUP

ISSUES:

a) Would new SPEED generation projects be more valuable as load reducers or registered with ISO New England as a generator?

b) If yes, how do we do it?
   - Reduce each utility's load prior to original settlement with ISO?
   - Reduce each utility's load for ISO's 90-Day re-settlement?
   - Financial settlement among utilities at end of the month?

The following tables and text show attempt to summarize the potential impacts on the Host Utility, the Project and the Non-Host Utilities of SPEED projects that are ***allocated to all utilities***. (If projects sell all output to the host utility then these impacts and all inequities are eliminated) compared to if the project was a generating asset registered with the ISO.

Energy Market

Host Utility	Project	Non-Host Utilities	Monthly Impact on VT
Costs reduced because loads are reduced.		Costs are increased because it doesn't receive generation credit in Energy Market it would otherwise receive.	Project location specific. Not able to determine ahead of time.

Notes:

1. MWHs of load reduction for Host = MWH lost generation for Non-Hosts.
2. Host Savings $ will differ from Non-Host $ of lost generation by the difference in RTM LMP between VT Load Zone and node generator would have settled at.
3. Whether or not Host $ Savings > Non-Host $ increase will be project specific.

Capacity Market

Host Utility	Project	Non-Host Utilities	Monthly Impact on VT
Costs reduced because ICAP requirements are reduced due to loads being lower.		Costs are increased because it doesn't receive generation credit in Capacity Market it would otherwise receive.	Likely a savings, but will be dependent upon output of unit at time of ISO peak time (1+reserve %) compared to credit it would have received in capacity market.
		Will see slightly higher costs because % share of NEPOOL ICAP requirement will be slightly higher as a result of host utility's being slightly lower. (This will be spread across all of NE)	

Notes:

1. If unit is generating at time of ISO peak Host savings likely > Non-Host increase but it is dependent upon how much capacity the unit would be paid for in the capacity market (For solar this likelihood is high, for wind ?)..
2. Non-host increase due to greater % share of NEPOOL ICAP requirements (as a result of Host % being smaller) will be very small and likely not small enough to make up difference in # 1 above.

Renewable Energy Credits (REC) Market

Host Utility	Project	Non-Host Utilities	Monthly Impact on VT
Initially receives all RECs.		Initially receive no RECs. Therefore must have RECs transferred to it or equivalent $ if that is sufficient.	$0
Will have to report generation to NEPOOL GIS Admin.			

Notes:
1. Third party verification of meter reading will be required.
2. RECs can be transferred from Host Utility to Non-Host Utility through NEPOOL GIS System.

Transmission

Host Utility	Project	Non-Host Utilities	Monthly Impact on VT
VELCO transmission costs will be reduced because % of load at time of peak will be smaller.		VELCO transmission costs will be increased because % of load at time of peak will be smaller.	$0
NEPOOL RNS, SO OATT ISO SFT Schedules 1 and 5 costs will be reduced because % of load at time of peak will be smaller.			Savings approximately = $5.23/kw-month x output at time of ISO Peak under current rates.
ISO Tariff Schedule 2 costs will decrease because VMs for load will decrease plus generation VM for its share of output will be avoided. Current rate is $0.18/MWH . TU's not impacted if counted as a generator.		ISO Tariff Schedule 2 generation VM will decrease because VM for share of output will be avoided.	Savings = $0.18/MWh x project output.
ISO Tariff 3 Expenses will be reduced by ISO Tariff Sched 3 Part 2 rate times reduction in utility's peak for month. Current rate is $135.93/MW-month.			Savings = $135.93 x MW reduction in utility peak.
May lose transmission revenue from project if it otherwise would have paid wheeling to host. (Being addressed by a separate committee).	*May* save transmission costs if it otherwise would have paid wheeling to host. (Being addressed by a separate committee).		

Ancillary Services Markets and Other Charges/Credits

Host Utility	Project	Non-Host Utilities	Monthly Impact on VT
Reserve Market costs reduced because settlement load is reduced and Reserve Market costs are allocated on hourly load obligation.			Saving approximately $0.20 - $1.25 x output of project depending on applicable auction prices and other market factors.
Regulation Market costs reduced because settlement load is reduced and Regulation costs are allocated on hourly load obligation. (approximately $0.20 - $0.60/MWH of Load Obligation depending on market prices at time)			Savings approximately $0.20 - $0.60 x output of project depending on market prices at time.
Marginal Loss Revenue credit reduced because allocated on real time load obligation.		Theoretical increase in Marginal Loss Revenue credit for all load serving entities in NE because or reduction for host.	Cost but usually very small (June 2009 was < $0.01/MWH on average)
External Inadvertent Energy Cost Distribution cost/credit reduced because allocated on real-time load obligation. Some hours this is a savings some hours it is a cost.		Theoretical increase in External Inadvertent Energy Cost Distribution credit for all load serving entities in NE because or reduction for host.	Often savings, but can be a cost. (June 2009 was savings of < $0.11/MWH on average)
Auction Revenue Rights credit reduced because load of peak allocator is reduced.		Auction Revenue Rights credit increased by amount that equals, or is very close to, reduction for Host.	Approximately $0.
Need to look into other miscellaneous credit/charges.	Need to look into other miscellaneous credit/charges.	Need to look into other miscellaneous credit/charges.	

Notes:

1. Reserve and Regulation savings seen by the Host will not be recognized if units are settled through ISO markets.

ISO Financial Assurance Policy

Host Utility	Project	Non-Host Utilities	Monthly Impact on VT
Since Energy, Capacity and Transmission costs through ISO are reduced FAP requirements will be reduced.		Since Energy, Capacity and Transmission costs through ISO are higher FAP requirements will be higher.	Unknown.

Notes:

1. Issue goes away if load is reduced prior to ISO settlement.

Attachment B

Example of Reporting Paths for NEPOOL GIS